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Wetzel et al.

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(54) **SEAL AROUND BRAIDED CABLE**

(75) Inventors: **James Rudolph Wetzel**, Houston, TX (US); **Nicolas A. Garibay**, Houston, TX (US); **Neil Griffiths**, Houston, TX (US)

(73) Assignee: **ZEITECS B.V.**, Rijswijk (NL)

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E21B 33/072 (2006.01)
E21B 43/12 (2006.01)

(52) **U.S. Cl.**
CPC ***E21B 33/072*** (2013.01); ***E21B 43/128*** (2013.01)

(58) **Field of Classification Search**
CPC E21B 43/128; E21B 33/072
USPC 264/338; 425/543
See application file for complete search history.

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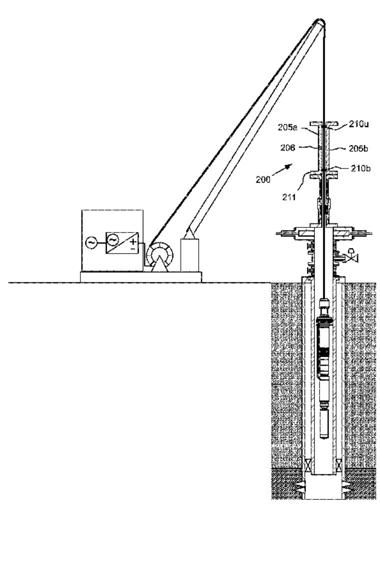
Primary Examiner — David Andrews
(74) *Attorney, Agent, or Firm* — Michael Stonebrook

(57) **ABSTRACT**

A method of deploying a downhole tool into a wellbore includes: lowering a cable into the wellbore; after lowering the cable, engaging a mold with an outer surface of the cable; injecting sealant into the mold and into armor of the cable, thereby sealing a portion of the cable; lowering the downhole tool to a deployment depth using the cable; engaging a seal with the sealed portion of the cable; and operating the downhole tool using the cable.

12 Claims, 8 Drawing Sheets



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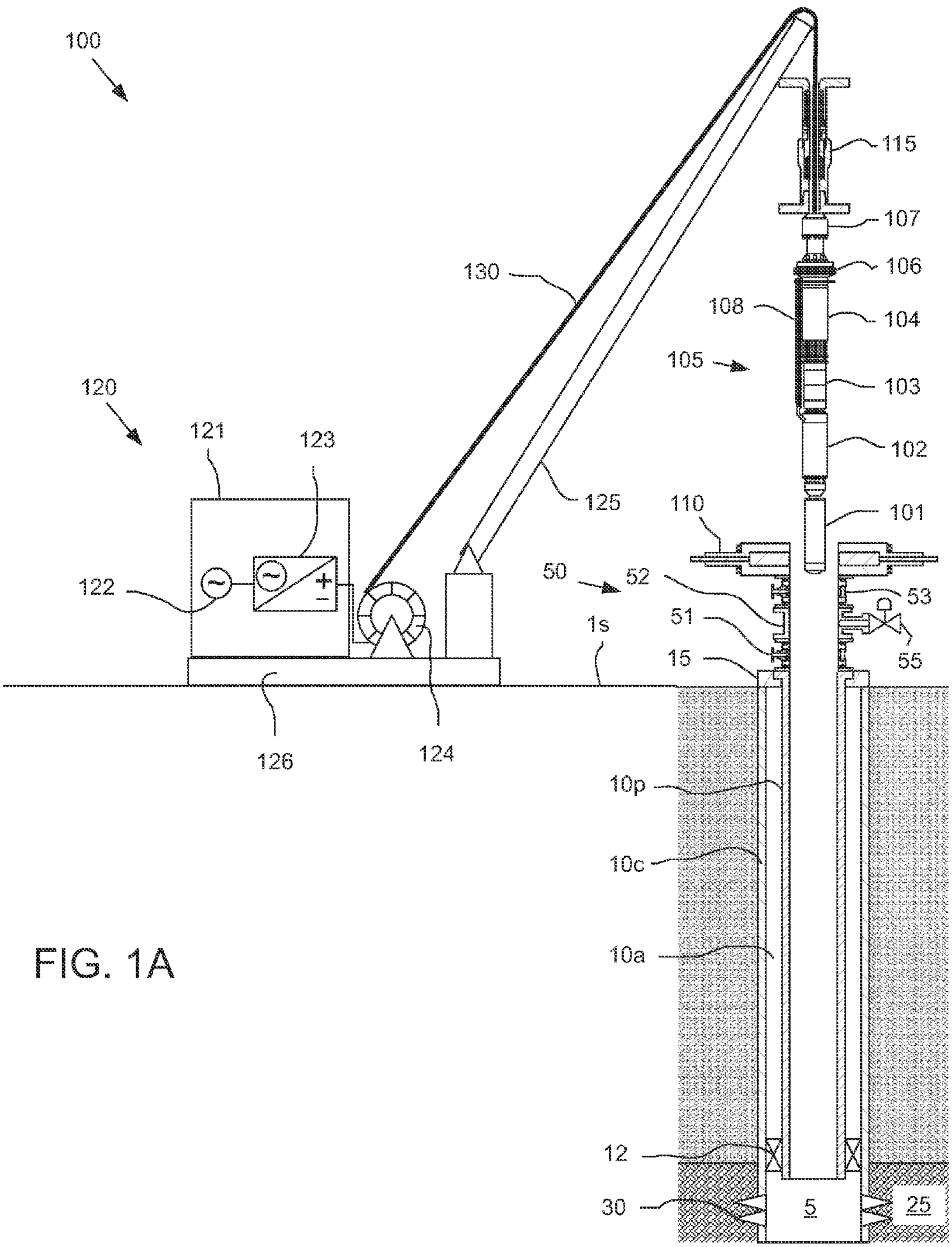
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FIG. 1A

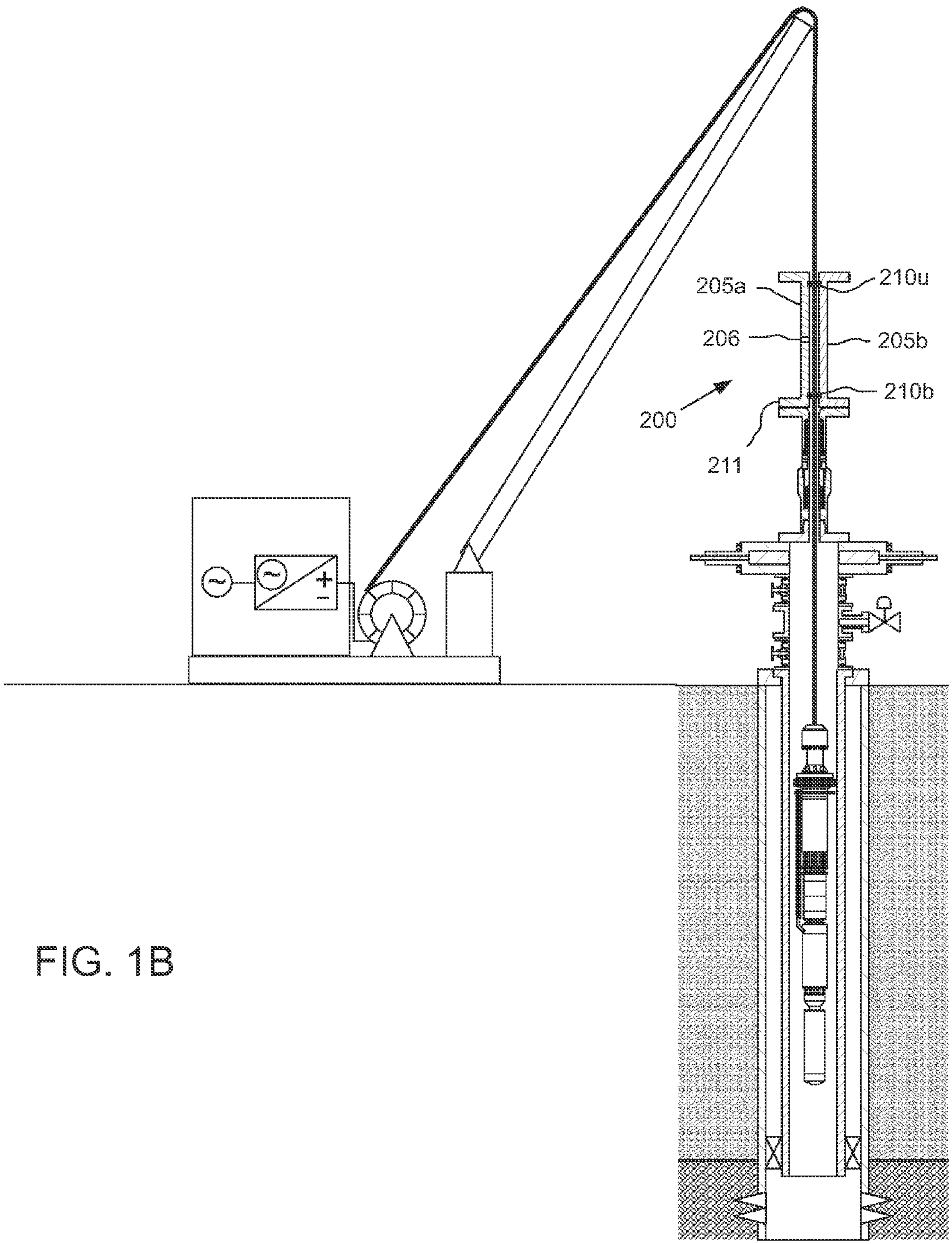

FIG. 1B

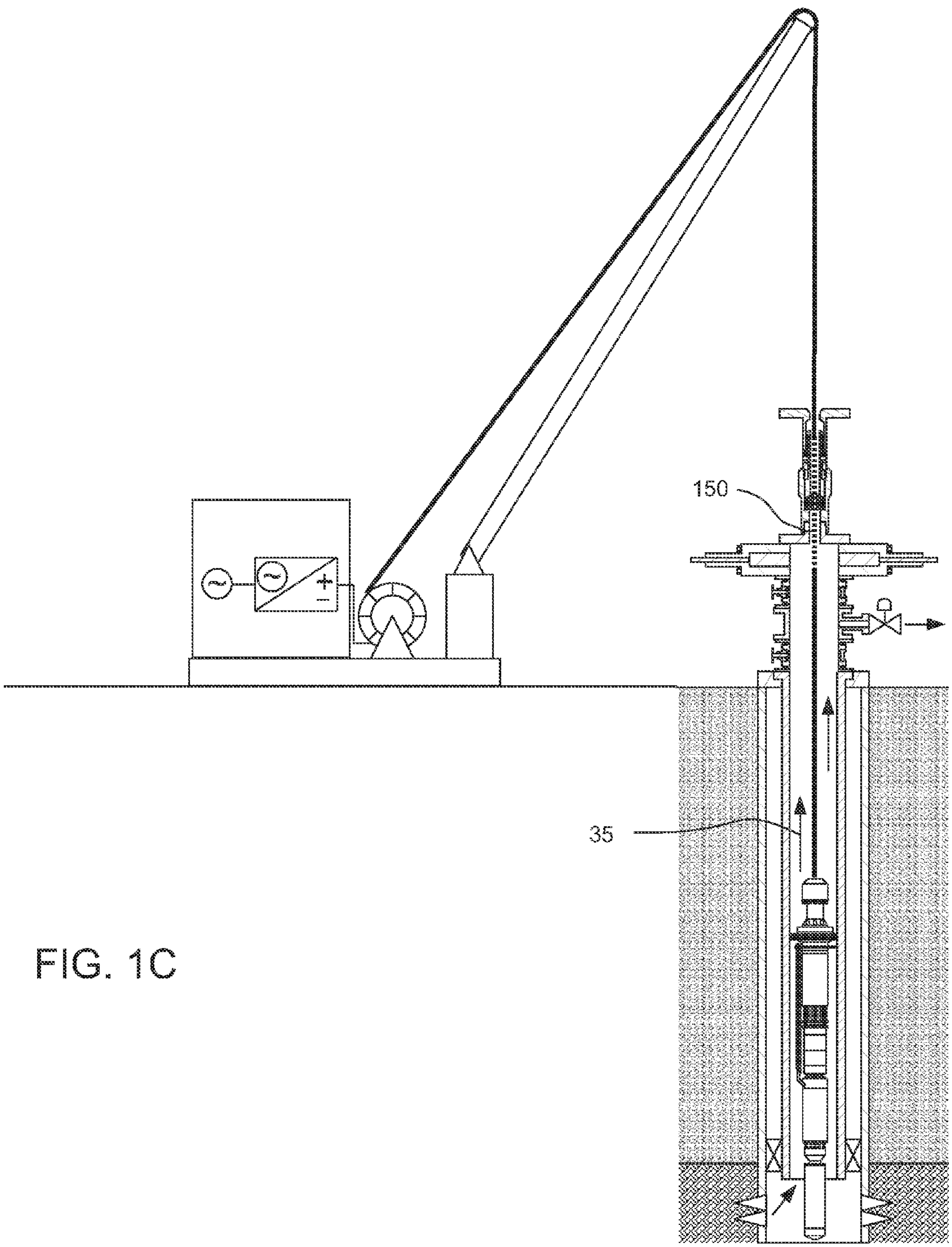

FIG. 1C

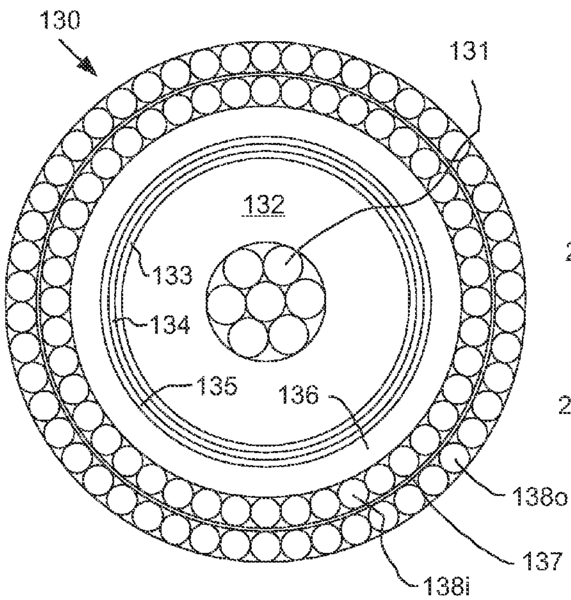

FIG. 2A

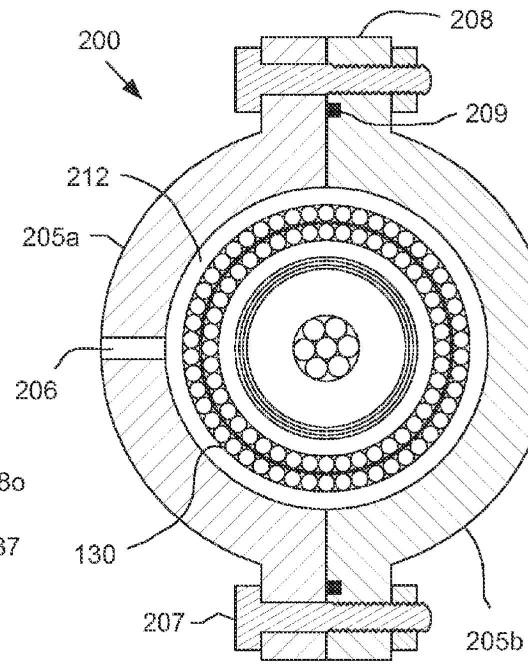

FIG. 2B

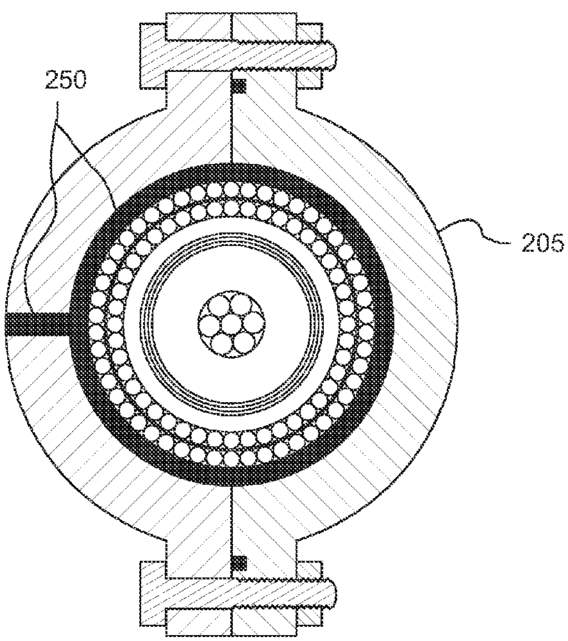

FIG. 2C

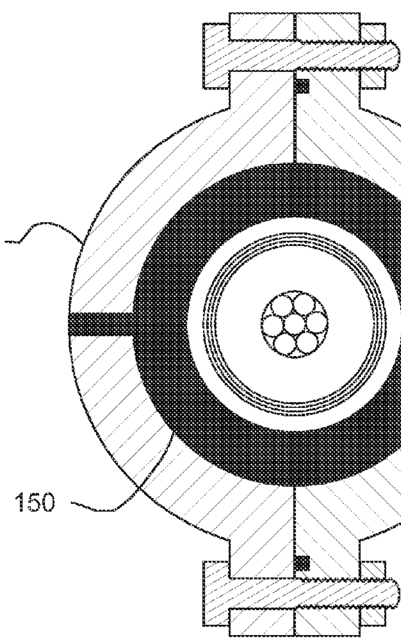

FIG. 2D

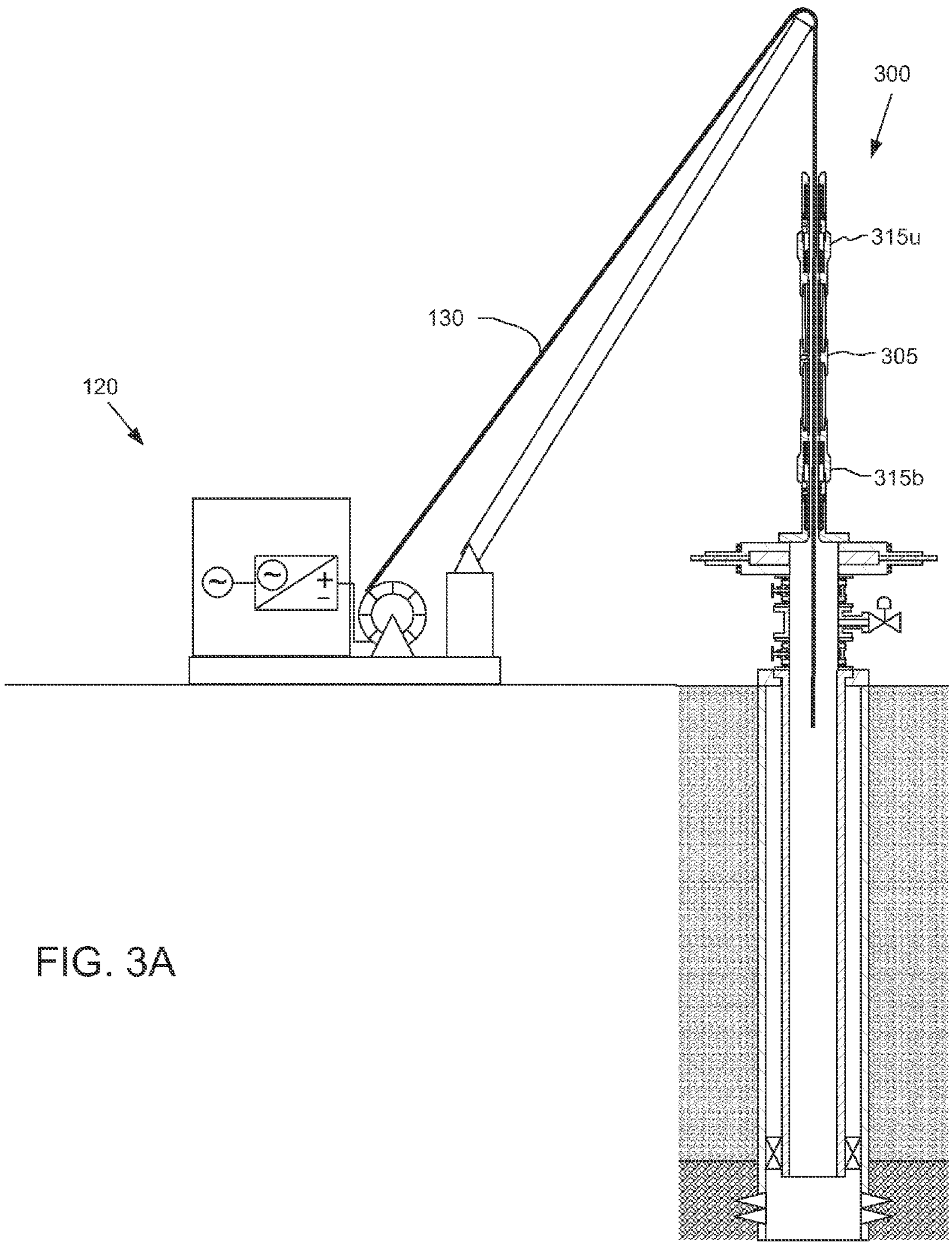

FIG. 3A

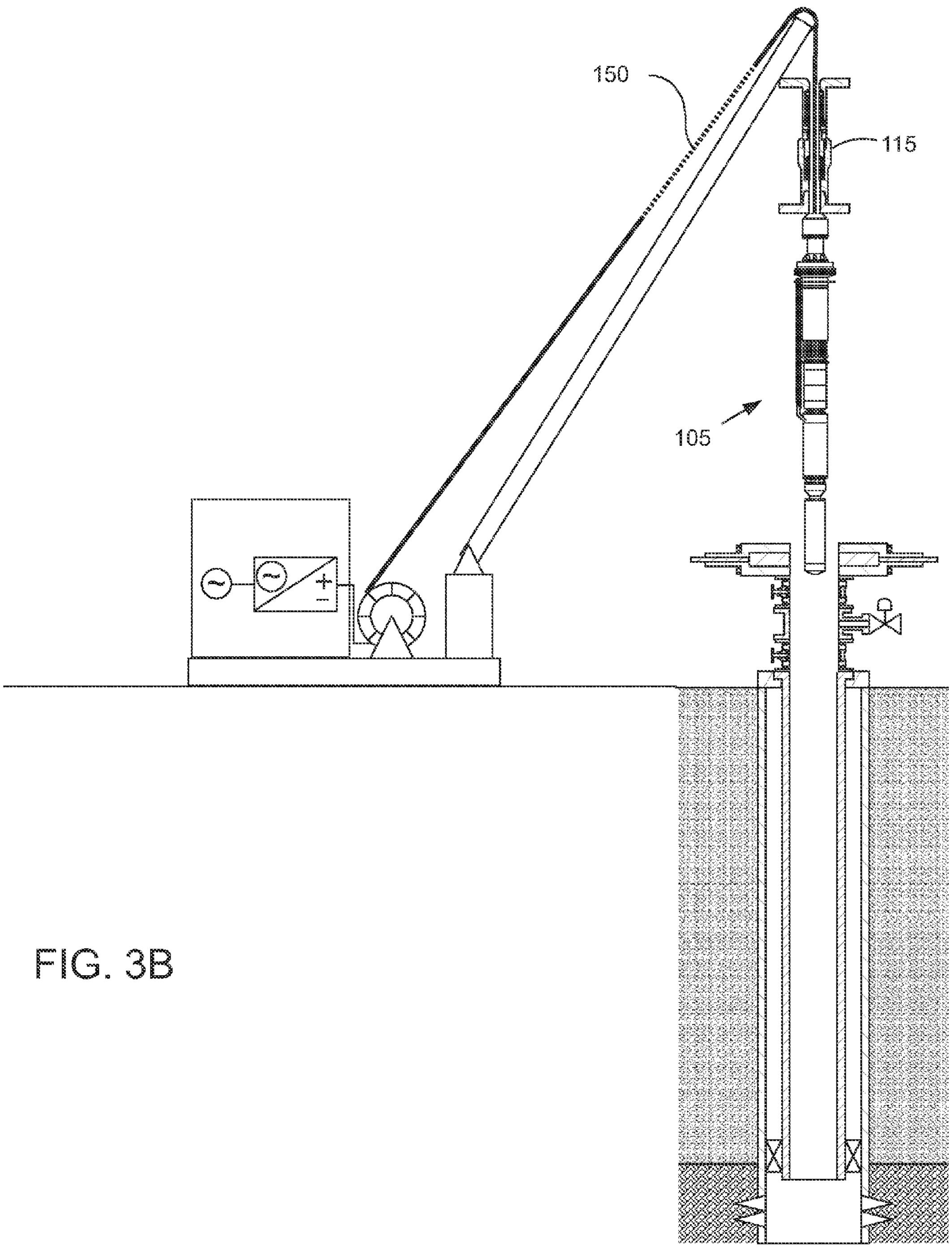

FIG. 3B

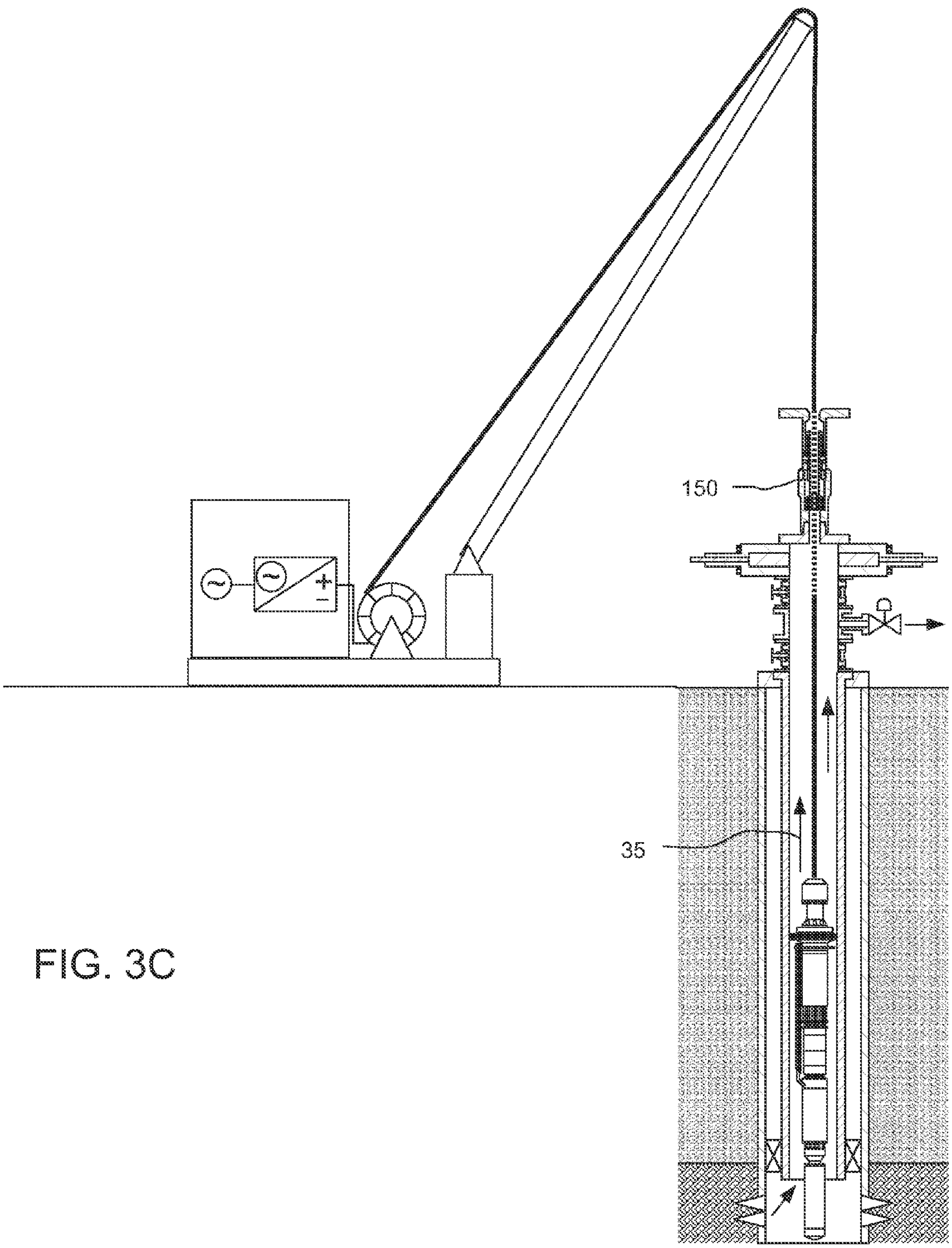

FIG. 3C

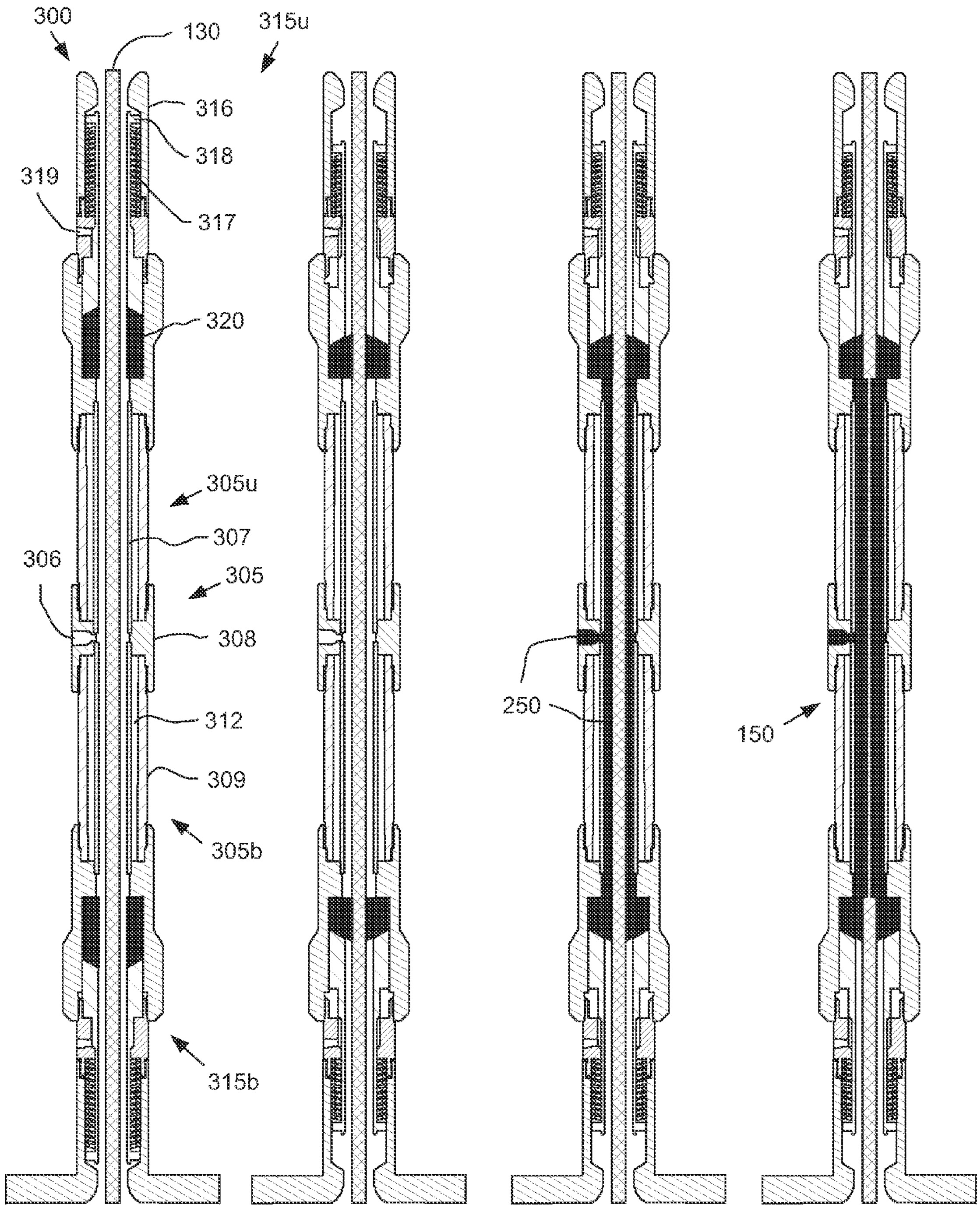

FIG. 4A FIG. 4B FIG. 4C FIG. 4D

SEAL AROUND BRAIDED CABLE

CROSS-REFERENCE TO RELATED APPLICATIONS

This application claims benefit of U.S. provisional Pat. App. No. 61/487,945, filed May 19, 2011, which is herein incorporated by reference in its entirety.

BACKGROUND OF THE INVENTION

1. Field of the Invention

Embodiments of the present invention generally relate to a seal around a braided cable.

2. Description of the Related Art

In the oil and gas industry, the term wireline typically refers to a cable used by operators of oil and gas wells to lower downhole tools, such as logging sensors, into a wellbore for purposes of well intervention and reservoir evaluation. The wireline may be a braided line and may contain an inner core of insulated wires, which provide power to equipment located at the end of the wireline, and provides a pathway for electrical telemetry for communication between the surface and equipment at the end of the wireline. The wireline resides on the surface, wound around a large diameter (e.g., 3 to 10 feet diameter) spool of a winch. The winch may be portable (e.g., on the back of a truck) or a semi-permanent part of the drilling rig. The winch may include a motor and drive train operable to turn the spool, thereby raising and lowering the tools into and out of the well.

A pressure control head is also employed during wireline operations to contain pressure originating from the wellbore. However, braided cable presents problems as pressure is likely to communicate between and under the multiple strands of the braid. For this reason, the pressure control head includes a grease injector for injecting thick grease into and around the cable in conjunction with a stuffing box for sealing against an outer surface of the cable while allowing the wireline to slide through. However, if a more semi-permanent stationary seal is required around the braided cable (for example, in the deployment of a power cable suspended electric submersible pump (ESP) system) continuous grease injection may not be convenient.

SUMMARY OF THE INVENTION

Embodiments of the present invention generally relate to a seal around a braided cable. In one embodiment, a method of deploying a downhole tool into a wellbore includes: lowering a cable into the wellbore; after lowering the cable, engaging a mold with an outer surface of the cable; injecting sealant into the mold and into armor of the cable, thereby sealing a portion of the cable; lowering the downhole tool to a deployment depth using the cable; engaging a seal with the sealed portion of the cable; and operating the downhole tool using the cable.

In another embodiment, a cable for deploying and operating a downhole tool includes: one or more electrical conductors extending a length of the cable; a jacket disposed around each conductor and extending the cable length; one or more layers of armor disposed around the jackets; sealant impregnated in the armor and extending only a portion of the cable length. The cable length is greater than or equal to five hundred feet. A length of the sealed portion is less than or equal to one-tenth of the cable length.

BRIEF DESCRIPTION OF THE DRAWINGS

So that the manner in which the above recited features of the present invention can be understood in detail, a more particular description of the invention, briefly summarized above, may be had by reference to embodiments, some of which are illustrated in the appended drawings. It is to be noted, however, that the appended drawings illustrate only typical embodiments of this invention and are therefore not to be considered limiting of its scope, for the invention may admit to other equally effective embodiments.

FIGS. **1**A-**1**C illustrate deployment of an electric submersible pump (ESP) into a wellbore, according to one embodiment of the present invention. FIG. **1**A illustrates the ESP and a stuffing box being lowered toward a production tree. FIG. **1**B illustrates installation of a mold around the cable. FIG. **1**C illustrates the ESP deployed and operating.

FIGS. **2**A-**2**D illustrate molding a portion of a cable with sealant. FIG. **2**A illustrates the cable. FIG. **2**B illustrates the mold assembled around the cable. FIG. **2**C illustrates injection of sealant into the mold. FIG. **2**D illustrates a portion of the cable impregnated by the sealant.

FIGS. **3**A-**3**C illustrate deployment of the ESP into the wellbore, according to another embodiment of the present invention. FIG. **3**A illustrates a mold connected to the blowout preventer (BOP). FIG. **3**B illustrates the ESP and the stuffing box being lowered toward the tree. FIG. **3**C illustrates the ESP deployed and operating.

FIGS. **4**A-**4**D illustrate molding a portion of the cable with sealant. FIG. **4**A is an enlargement of a portion of FIG. **3**A illustrating the cable extending through the mold. FIG. **4**B illustrates seals of the mold engaged with the cable. FIG. **4**C illustrates injection of sealant into the mold. FIG. **4**D illustrates a portion of the cable impregnated by the sealant.

DETAILED DESCRIPTION

FIGS. **1**A-**1**C illustrate deployment of an electric submersible pump (ESP) **105** into a wellbore **5**, according to one embodiment of the present invention. FIG. **1**A illustrates the ESP **105** and a stuffing box **115** being lowered toward a production tree **50**. The ESP **105** may be part of an artificial lift system (ALS) **100**. The ALS **100** may include the ESP **105**, a blowout preventer (BOP) **110** or BOP stack (only one BOP shown), the stuffing box **115**, and a launch and recovery system (LARS) **120**.

The wellbore **5** has been drilled from a surface **1***s* of the earth into a hydrocarbon-bearing (i.e., crude oil and/or natural gas) reservoir **25**. A string of casing **10***c* has been run into the wellbore **5**, hung from a wellhead **15**, and set therein with cement (not shown). The casing **10***c* has been perforated **30** to provide to provide fluid communication between the reservoir **25** and a bore of the casing **10***c*. A string of production tubing **10***p* extends from the wellhead **15** to the reservoir **25** to transport production fluid **35** (FIG. **1**C) from the reservoir **25** to the surface **1***s*. A packer **12** has been set between the production tubing **10***p* and the casing **10***c* to isolate an annulus **10***a* formed between the production tubing and the casing from production fluid **35**.

The production (aka Christmas) tree **50** may be installed on the wellhead **15**. The production tree **50** may include a master valve **51**, tee **52**, a swab valve **53**, a cap (not shown), and a production choke **55**. Production fluid **35** from the reservoir **25** may enter a bore of the production tubing **10***p*, travel through the tubing bore to the surface **1***s*. The production fluid may continue through the master valve **51**, the tee **52**, and through the choke **55** to a flow line (not shown). The production fluid **35** may continue through the flowline to surface separation, treatment, and storage equipment (not shown). The reservoir **25** may be dead due to depletion or kill fluid or the reservoir may be live and isolated by a subsurface safety valve (not shown), thereby obviating the need for a lubricator (not shown). Alternatively, the wellbore **5** may be live and the lubricator may be employed to lower the ESP into the wellbore.

To prepare for insertion of the ESP **105** into the wellbore **5**, one or more trucks (not shown) may deliver the ALS system **100** to the wellsite. The LARS **120** may include a control room **121**, a winch **124** having cable **130** wrapped therearound, a boom **125**, a generator **122**, a controller **123**, and a skid frame **126**. The generator **122** may be diesel-powered and provide alternating current (AC) power. The LARS controller **123** may include a transformer (not shown) for stepping the voltage of the AC power signal from the generator **122** from a low voltage signal to a medium voltage signal. The low voltage signal may be less than or equal to one kilovolt (kV) and the medium voltage signal may be greater than one kV, such as three to ten kV. The LARS controller **123** may further include a rectifier for converting the medium voltage AC signal to a medium voltage direct current (DC) power signal for transmission downhole via the cable **130**. The LARS controller **123** may be in electrical communication with the cable **130** via leads and an electrical coupling (not shown), such as brushes or slip rings, to allow power transmission through the cable while the winch **124** winds and unwinds the cable **130**. The LARS controller **123** may further include a data modem (not shown) and a multiplexer (not shown) for modulating and multiplexing a data signal to/from the downhole controller with the DC power signal. The winch **124** may include an electric or hydraulic motor (not shown) and a drum rotatable by the motor for winding or unwinding of the cable **130**.

The ESP **105** may include an electric motor **101**, a power conversion module (PCM) **102**, a seal section **103**, a pump **104**, an isolation device **106**, a cablehead **107**, and a flat cable **108**. Housings of each of the ESP components may be longitudinally and rotationally connected, such as by flanged or threaded connections. The cablehead **107** may include a cable fastener (not shown), such as slips or a clamp for longitudinally connecting the ESP to the cable **130**. Since the power signal may be DC, the cable **130** may only include two conductors arranged coaxially (discussed more below).

The cable **130** may be longitudinally coupled to the cablehead **107** by a shearable connection (not shown). The cable **130** may be sufficiently strong so that a margin exists between the deployment weight and the strength of the cable. For example, if the deployment weight is ten thousand pounds, the shearable connection may be set to fail at fifteen thousand pounds and the cable may be rated to twenty thousand pounds. The cablehead **107** may further include a fishneck so that if the ESP **105** become trapped in the wellbore **5**, such as by jamming of the isolation device **106** or buildup of sand, the cable **130** may be freed from rest of the components by operating the shearable connection and a fishing tool (not shown), such as an overshot, may be deployed to retrieve the ESP **105**.

The cablehead **107** may also include leads (not shown) extending therethrough and through the isolation device **106**. The leads may provide electrical communication between the conductors of the cable **130** and conductors of the flat cable **108**. The flat cable **108** may extend along the pump **104** and the seal section **102** to the PCM **102**. The flat cable **108** may have a low profile to account for limited annular clearance between the components **103**, **104** and the production tubing **10***p*. Since the flat cable **108** may conduct the DC signal, the flat cable may only require two conductors (not shown) and may only need to support its own weight. The flat cable **108** may be armored by a metal or alloy.

The motor **101** may be an induction motor, a switched reluctance motor (SRM) or a permanent magnet motor, such as a brushless DC motor (BLDC). The motor **101** may be filled with a dielectric, thermally conductive liquid lubricant, such as motor oil. The motor **101** may be cooled by thermal communication with the production fluid **35**. The motor **101** may include a thrust bearing (not shown) for supporting a drive shaft (not shown). In operation, the motor **101** may rotate the drive shaft, thereby driving a pump shaft (not shown) of the pump **104**. The drive shaft may be directly connected to the pump shaft (no gearbox).

The induction motor may be a two-pole, three-phase, squirrel-cage induction type and may run at a nominal speed of thirty-five hundred rpm at sixty Hz. The SRM motor may include a multi-lobed rotor made from a magnetic material and a multi-lobed stator. Each lobe of the stator may be wound and opposing lobes may be connected in series to define each phase. For example, the SRM motor may be three-phase (six stator lobes) and include a four-lobed rotor. The BLDC motor may be two pole and three phase. The BLDC motor may include the stator having the three phase winding, a permanent magnet rotor, and a rotor position sensor. The permanent magnet rotor may be made of one or more rare earth, ceramic, or cermet magnets. The rotor position sensor may be a Hall-effect sensor, a rotary encoder, or sensorless (i.e., measurement of back EMF in undriven coils by the motor controller).

The PCM **102** may include a power supply, a motor controller (not shown), a modem (not shown), and demultiplexer (not shown). The power supply may include one or more DC/DC converters, each converter including an inverter, a transformer, and a rectifier for converting the DC power signal into an AC power signal and reducing the voltage from medium to low. Each converter may be a single phase active bridge circuit as discussed and illustrated in PCT Publication WO 2008/148613, which is herein incorporated by reference in its entirety. The power supply may include multiple DC/DC converters in series to gradually reduce the DC voltage from medium to low. For the SRM and BLDC motors, the low voltage DC signal may then be supplied to the motor controller. For the induction motor, the power supply may further include a three-phase inverter for receiving the low voltage DC power signal from the DC/DC converters and outputting a three phase low voltage AC power signal to the motor controller.

For the induction motor, the motor controller may be a switchboard (i.e., logic circuit) for simple control of the motor at a nominal speed or a variable speed drive (VSD) for complex control of the motor. The VSD controller may include a microprocessor for varying the motor speed to achieve an optimum for the given conditions. The VSD may also gradually or soft start the motor, thereby reducing start-up strain on the shaft and the power supply and minimizing impact of adverse well conditions.

For the SRM or BLDC motors, the motor controller may receive the low voltage DC power signal from the power supply and sequentially switch phases of the motor, thereby supplying an output signal to drive the phases of the motor. The output signal may be stepped, trapezoidal, or sinusoidal. The BLDC motor controller may be in communication with the rotor position sensor and include a bank of transistors or thyristors and a chopper drive for complex control (i.e., variable speed drive and/or soft start capability). The SRM motor controller may include a logic circuit for simple control (i.e. predetermined speed) or a microprocessor for complex control (i.e., variable speed drive and/or soft start capability). The SRM motor controller may use one or two-phase excitation, be unipolar or bi-polar, and control the speed of the motor by controlling the switching frequency. The SRM motor controller may include an asymmetric bridge or half-bridge.

The modem and demultiplexer may demultiplex a data signal from the DC power signal, demodulate the signal, and transmit the data signal to the motor controller. The motor controller may be in data communication with one or more sensors (not shown) distributed throughout the ESP **105**. A pressure and temperature (PT) sensor may be in fluid communication with the reservoir fluid **35** entering an inlet of the pump **104**. A gas to oil ratio (GOR) sensor may also be in fluid communication with the reservoir fluid **35** entering the pump inlet. A second PT sensor may be in fluid communication with the reservoir fluid **35** discharged from an outlet of the pump **104**. A temperature sensor (or PT sensor) may be in fluid communication with the lubricant to ensure that the motor **101** and PCM **102** are being sufficiently cooled. Multiple temperature sensors may also be included in the PCM **102** for monitoring and recording temperatures of the various electronic components. A voltage meter and current (VAMP) sensor may be in electrical communication with the cable **130** to monitor power loss from the cable. A second VAMP sensor may be in electrical communication with the power supply output to monitor performance of the power supply. Further, one or more vibration sensors may monitor operation of the motor **101**, the pump **104**, and/or the seal section **103**. A flow meter may be in fluid communication with the pump outlet for monitoring a flow rate of the pump **104**. Utilizing data from the sensors, the motor controller may monitor for adverse conditions, such as pump-off, gas lock, or abnormal power performance and take remedial action before damage to the pump **104** and/or motor **101** occurs.

The seal section **103** may isolate the reservoir fluid **35** being pumped through the pump **104** from the lubricant in the motor **101** by equalizing the lubricant pressure with the pressure of the reservoir fluid **35**. The seal section **103** may rotationally connect the drive shaft to the pump shaft. The seal section **103** may house a thrust bearing capable of supporting thrust load from the pump **104**. The seal section **103** may be positive type or labyrinth type. The positive type may include an elastic, fluid-barrier bag to allow for thermal expansion of the motor lubricant during operation. The labyrinth type may include tube paths extending between a lubricant chamber and a reservoir fluid chamber providing limited fluid communication between the chambers.

The pump inlet may be standard type, static gas separator type, or rotary gas separator type depending on the GOR of the production fluid **35**. The standard type inlet may include a plurality of ports allowing reservoir fluid **35** to enter a lower or first stage of the pump **104**. The standard inlet may include a screen to filter particulates from the reservoir fluid **35**. The static gas separator type may include a reverse-flow path to separate a gas portion of the reservoir fluid **35** from a liquid portion of the reservoir fluid **35**.

The isolation device **106** may include a packer, an anchor, and an actuator. The actuator may be operated mechanically by articulation of the cable **130**, electrically by power from the cable, or hydraulically by discharge pressure from the pump **104**. The packer may be made from a polymer, such as a thermoplastic, elastomer, or copolymer, such as rubber, polyurethane, or PTFE. The isolation device **106** may have a bore formed therethrough in fluid communication with the pump outlet and have one or more discharge ports formed above the packer for discharging the pressurized reservoir fluid into the production tubing **10***p*. Once the ESP **105** has reached deployment depth, the isolation device actuator may be operated, thereby setting the anchor and expanding the packer against the production tubing **10***p*, isolating the pump inlet from the pump outlet, and rotationally connecting the ESP **105** to the production tubing. The anchor may also longitudinally support the ESP **105**.

Additionally, the isolation device **106** may include a bypass vent (not shown) for releasing gas separated by the pump inlet that may collect below the isolation device and preventing gas lock of the pump **104**. A pressure relief valve (not shown) may be disposed in the bypass vent. Additionally, a downhole tractor (not shown) may be integrated into the cable **130** to facilitate the delivery of the ESP **105**, especially for highly deviated wells, such as those having an inclination of more than forty-five degrees or dogleg severity in excess of five degrees per one hundred feet. The drive and wheels of the tractor may be collapsed against the cable and deployed when required by a signal from the surface.

The pump **104** may be centrifugal or positive displacement. The centrifugal pump may be a radial flow or mixed axial/radial flow. The positive displacement pump may be progressive cavity. The pump **104** may include one or more stages (not shown). Each stage of the centrifugal pump may include an impeller and a diffuser. The impeller may be rotationally and longitudinally connected to the pump shaft, such as by a key. The diffuser may be longitudinally and rotationally coupled to a housing of the pump, such as by compression between a head and base screwed into the housing. Rotation of the impeller may impart velocity to the reservoir fluid **35** and flow through the stationary diffuser may convert a portion of the velocity into pressure. The pump **104** may deliver the pressurized reservoir fluid **35** to the isolation device bore.

Alternatively, the pump **104** may be a high speed compact pump discussed and illustrated at FIGS. 1C and 1D of U.S. patent application Ser. No. 12/794,547, filed Jun. 4, 2010, which is herein incorporated by reference in its entirety. High speed may be greater than or equal to ten thousand, fifteen thousand, or twenty thousand revolutions per minute (RPM). The compact pump may include one or more stages, such as three. Each stage may include a housing, a mandrel, and an annular passage formed between the housing and the mandrel. The mandrel may be disposed in the housing. The mandrel may include a rotor, one or more helicoidal rotor vanes, a diffuser, and one or more diffuser vanes. The rotor may include a shaft portion and an impeller portion. The rotor may be supported from the diffuser for rotation relative to the diffuser and the housing by a hydrodynamic radial bearing formed between an inner surface of the diffuser and an outer surface of the shaft portion. The rotor vanes may interweave to form a pumping cavity therebetween. A pitch of the pumping cavity may increase from an inlet of the stage to an outlet of the stage. The rotor may be longitudinally and rotationally connected to the motor drive shaft and be rotated by operation of the motor. As the rotor is rotated, the production fluid **35** may be pumped along the cavity from the inlet toward the outlet. The annular passage may have a nozzle portion, a throat portion, and a diffuser portion from the inlet to the outlet of each stage, thereby forming a Venturi.

The tree cap may be removed from the tree **50**. The BOP **110** may be connected to the swab valve **53**, such as by fastening. The BOP **110** may include one or more ram BOPS, such as two. The first ram BOP may include a pair of blind-shear rams (or separate blind rams and shear rams) capable of cutting the cable **130** when actuated and sealing the bore, and a second ram BOP may include a pair of cable rams for sealing against an outer surface of the cable **130** when actuated. The LARS **120** may further include a hydraulic power unit (HPU, not shown) for operating the BOP stack **110**. Once the BOP **110** has been installed, the cable **130** may then be inserted through the stuffing box **115** and fastened to the cablehead **105**. The boom **125** may be used to hoist the ESP and stuffing box over the BOP **110**. The swab valve **53** and master valve **51** may then be opened. The ESP **105** may be lowered through the tree **50** and into the wellbore until the stuffing box **115** engages the BOP **110**. Lowering may be halted and the stuffing box **115** may be fastened to the BOP **110**, such as by a flanged connection. Lowering of the ESP **105** into the wellbore **5** may resume until the ESP is proximately above deployment depth.

FIG. **1**B illustrates installation of a mold **200** around the cable **130**. The winch **124** may be locked with the ESP **105** in the wellbore **5** proximately above deployment depth. Alternatively, the isolation device **106** may be set to support the ESP **105**. The mold **200** may be assembled around the cable **130** above the stuffing box **115**.

FIGS. **2**A-**2**D illustrate molding a portion **150** of the cable **130** with sealant **250**. FIG. **2**A illustrates the cable **130**. The cable **130** may include an inner core **131**, an inner jacket **132**, a shield **133**, an outer jacket **136**, and one or more layers **138***i,o* of armor.

The inner core **131** may be the first conductor and made from an electrically conductive material, such as aluminum, copper, or alloys thereof. The inner core **131** may be solid or stranded (shown). The inner jacket **132** may electrically isolate the core **131** from the shield **133** and be made from a dielectric material, such as a polymer. The shield **133** may serve as the second conductor and be made from the electrically conductive material. The shield **133** may be tubular (shown), braided, or a foil covered by a braid. The outer jacket **136** may electrically isolate the shield **133** from the armor **138***i,o* and be made from an oil-resistant dielectric material. The armor may be made from one or more layers **138***i,o* of high strength material (i.e., tensile strength greater than or equal to one hundred, one fifty, or two hundred kpsi) to support the deployment weight (weight of the cable **130** and the weight of the ESP **105**)) so that the cable **130** may be used to deploy and remove the ESP **105** into/from the wellbore **5**. The high strength material may be a metal or alloy and corrosion resistant, such as galvanized steel or a nickel alloy depending on the corrosiveness of the reservoir fluid **35**. The armor may include two contra-helically wound layers **138***i,o* of wire or strip.

Additionally, the cable **130** may include a sheath **135** disposed between the shield **133** and the outer jacket **136**. The sheath **135** may be made from lubricative material, such as polytetrafluoroethylene (PTFE) or lead, and may be tape helically wound around the shield **133**. If lead is used for the sheath **135**, a layer of bedding **134** may insulate the shield **133** from the sheath and be made from the dielectric material. Additionally, a buffer **137** may be disposed between the armor layers **138***i,o*. The buffer **137** may be tape and may be made from the lubricative material. The buffer **137** may be perforated to allow sealant flow to the inner armor layer **138***i*

Due to the coaxial arrangement, the cable **130** may have an outer diameter less than or equal to one and one-quarter inches, one inch, or three-quarters of an inch. Alternatively, the conductors **131**, **133** may be eccentrically arranged and/or the cable **130** may include three or more conductors, such as three, and conduct three-phase AC power to the motor **101** (obviating the PCM **102**). Alternatively, the cable **130** may include only one conductor and the production tubing **10***p* may be used for the other conductor.

FIG. **2**B illustrates the mold **200** assembled around the cable **130**. The mold **200** may be delivered to the wellsite by a service truck (not shown). The service truck may include a reaction injector and a crane or platform to lift the mold to a top of the stuffing box. The reaction injector may include a pair of supply tanks each having a liquid reactive component (aka resin and hardener) stored therein. The supply tanks or the components may or may not be heated. The service truck may further include a pair of feed pumps, each having an inlet connected to a respective supply tank. An outlet of each supply pump may be connected to a mix head and an outlet of the mix head may connect to the mold **200**. The service truck may further include an HPU for powering the supply pumps. The service truck may further include a controller for proportioning the feed pumps. The feed pumps may be operated to simultaneously supply the liquid reactive components to the mix head. The mix head may impinge the liquid components to begin polymerization of the sealant mixture **250**. The sealant mixture **250** may continue from the mix head into the mold **200**.

Alternatively, the service truck may include an injector, a crane or platform to lift the injector and the mold to a top of the stuffing box, and an HPU to power the injector. The injector may include a hopper, a barrel, a driver, and a heater. The heater may surround the mold side of the barrel. The driver may be a rotating screw disposed in the barrel. The screw may have a feed section, transition section, and a metering section. The feed section may receive sealant pellets from the hopper and convey them to the transition section. The transition section may compress the pellets into a molten sealant and pump the molten sealant to the metering section. The screw may be supported by a hydraulic ram that is displaced away from the mold by the sealant feed through the screw. The hydraulic ram may then reverse to inject the molten sealant into the mold. Alternatively, the driver may be a hydraulic plunger and a torpedo spreader.

The mold **200** may include a split housing **205** and upper **210***u* and lower **210***b* seals (FIG. **1**B). The housing **205** may include a pair of mating semi-tubular segments **205***a,b*. Each housing segment **205***a,b* may have radial couplings, such as flanges **208**, formed therealong and half of a longitudinal coupling **211** formed at one or both longitudinal ends thereof. The radial flanges **208** of each housing segment **205***a,b* may be connected to the mating radial flanges by fasteners **207**, such as bolts and nuts. A gasket **209** may be disposed in a groove formed in one of the housing segments for sealing the radial connection. Alternatively, the radial couplings may instead be a hinge and latch. Each seal **210***u,b* may include a pair of mating semi-annular segments. One segment of each seal **210***u,b* may include a coupling (not shown) formed at ends thereof, such as a ball and the other segment may include a mating coupling, such as a socket, so that the couplings mate when the housing **205** is assembled.

An inner diameter of the mold housing **205** may be slightly greater than an outer diameter of the cable **130**, thereby forming an annulus **212** between the mold housing and the cable. The housing **205** may have a sprue **206** formed through a wall of one of the segments **205***a,b* and in fluid communication with the annulus **212**. An inner diameter of the mold seals **210***u,b* may be slightly less than an outer diameter of the cable **130** so that the mold seals engage an outer surface of the cable when the mold **200** is assembled.

The service truck crane/platform may lift each of the housing segments **205***a,b* on to the stuffing box **115**. The housing segments **205***a,b* may be radially assembled around the cable **130** using the fasteners **207**. The assembled housing **205** may then be connected to the stuffing box **115** via the flange **211**. Alternatively, the housing **205** may just rest on the stuffing box **115**.

FIG. **2**C illustrates injection of sealant **250** into the mold **200**. The sealant **250** may be a polymer, such as a thermoplastic, elastomer, copolymer, or thermoset, such as polyisoprene, polybutadiene, polyisobutylene, polychloroprene, butadiene-styrene rubber, styrene-butadiene copolymer (thermoplastic elastomer), butadiene-acrylonitrile, acrylonitrile butadiene styrene (ABS), silicone, ethylene propylene diene monomer (EPDM) rubber, or polyurethane.

Once the mold **200** has been assembled around the cable **130**, the mix head may be lifted to the mold **200** by the service truck crane or the service truck platform may lift the reaction injector to the mold **200**. The mix head may be connected to the sprue **206**. The supply pumps may then be operated to pump the liquid reactants to the mix head. The sealant mixture **250** may continue from the mix head into the mold **200**. Air displaced by the sealant mixture **250** may vent from the mold via leakage through and along the armor **138***i,o*. The sealant mixture **250** may flow around and along the annulus **212** until the sealant mixture **250** encounters the seals **210***u,b*. Pressure in the mold **200** may increase and the sealant mixture **250** may be forced into the armor **138***i,o*. Sealant penetration into the cable **130** may be stopped by the outer jacket **136**. Pumping of the sealant mixture **250** may continue until the mold **200** is filled. The mold **200** may be heated by exothermic polymerization of the mixture **250**. A melting temperature of the mold seals **210***u,b*, gasket **209**, and outer jacket **136** may be suitable to withstand the exothermic reaction.

FIG. **2**D illustrates a portion **150** of the cable **130** impregnated by the sealant **250**. Once the sealant **250** has cured and cooled to at least a point sufficient to maintain structural integrity, the mix head may be disconnected from the mold **200** and the mold **200** may be disconnected from the stuffing box **115**. The fasteners **207** may then be removed. The service truck may further include a hydraulic spreader. The spreader may be connected to the mold **200** and operated to separate the mold. The service truck may stow the mold **200** and mix head and leave the wellsite.

A length of the sealed portion **150** may be greater than or equal to a length of a seal of the stuffing box **115**. For example, the sealed portion length may be greater than or equal to one foot, three feet, five feet, six feet, or ten feet. A length of the cable **130** may be greater than or equal to five hundred or one thousand feet. The sealed portion length may be substantially less than a length of the cable **130**, such as less than or equal to one-tenth, one hundredth, or one thousandth the cable length. An outer diameter of the sealed portion **150** may be slightly greater than an outer diameter of the rest of the cable **130**. Alternatively, the outer diameter of the sealed portion **150** may be equal to an outer diameter of the rest of the cable **130**, such as by eliminating the annulus **212** or trimming the sealed portion.

FIG. **1**C illustrates the ESP **105** deployed and operating. The winch **124** may then be unlocked and operated to lower the ESP **105** to deployment depth. As the ESP **105** is lowered, the sealed portion **150** may be lowered into alignment with the stuffing box seal. The isolation device **106** may then be set to engage the production tubing **10***p* and the stuffing box **115** may be operated to engaged the sealed portion **150**. The ESP **105** may then be operated to pump production fluid **35** from the wellbore **5** to the tree **50** and through the tree to the surface separation, treatment, and storage equipment.

FIGS. **3**A-**3**C illustrate deployment of the ESP **105** into the wellbore, **5** according to another embodiment of the present invention. FIG. **3**A illustrates a mold **300** connected to the BOP **110**. The service truck discussed above in conjunction with the mold **200** may deliver the mold **300** to the wellsite. The tree cap may be removed from the tree **50**. The BOP **110** may be connected to the swab valve **53**. The swab valve **53** and master valve **51** may then be opened. The cable **130** may then be inserted through the mold **300**. A cablehead (not shown) may be fastened to the cable **130** and used to lift the mold **300** over the BOP **110** and lower the mold on to the BOP. The mold **300** may then be fastened to the BOP **110**. Alternatively, the platform/crane of the service truck may be used to lift the mold **300** on to the BOP **110**. The mold **300** may then be fastened to the BOP **110** and the cable **130** may be inserted through the mold and the tree **50** into the wellbore **5**. The cable **130** may then be lowered into the wellbore **5** until proximately above the ESP deployment depth.

FIGS. **4**A-**4**D illustrate molding a portion **150** of the cable **130** with the sealant **250**. FIG. **4**A is an enlargement of a portion of FIG. **3**A illustrating the cable **130** extending through the mold **300**. The mold **300** may include a runner **305**, and upper **315***u* and lower **315***b* stuffing boxes. The runner **305** may include one or more tubular sections **305***u,b* connected by a coupling **308**. Each section **305***u,b* may include a housing **309** and an insert **307**. An annular coupling **308** may connect to each of the runner sections, such as by a threaded connection. Each housing **309** may also connect to a housing **316** of a respective stuffing box **315***u,b*, such as by a threaded connection. The coupling **308** may have a shoulder formed therein for receiving an end of each insert **307** and each stuffing box housing **316** may have a shoulder for receiving the other end of each insert. An inner diameter of the inserts **307** may be slightly greater than an outer diameter of the cable **130**, thereby forming an annulus **312** between the inserts **307** and the cable **130**. The coupling **308** may have a sprue **306** formed through a wall thereof in fluid communication with the annulus **312**.

Each stuffing box **315***u,b* may include a tubular housing **316**, a seal **320**, a piston **318**, and a spring **317**. Each housing **316** may include one or more sections and each housing section may be connected, such as by threads. A port **319** may be formed through the housing in communication with the piston **318**. The port **319** may be connected to the service truck HPU via a hydraulic conduit (not shown). When operated by hydraulic fluid, the piston **318** may longitudinally compress the seal **320**, thereby radially expanding the seal **320** inward into engagement with the cable **130**. The spring **317** may bias the piston **318** away from the seal **320**. Alternatively, the spring **317** may be omitted and bias from the seal **320** may be used to disengage the seal from the cable **130**.

FIG. **4**B illustrates seals **320** of the mold **300** engaged with the cable **130**. Once the cable **130** has been lowered to a depth proximately above the ESP deployment depth, hydraulic fluid may be supplied to the stuffing box ports **319**, thereby engaging the stuffing box seals **320** with the cable **130**.

FIG. **4**C illustrates injection of sealant **250** into the mold **300**. Once the seals **320** engage the cable **130**, the mix head may be connected to the sprue **306**. The sealant mixture **250** may then be pumped into the mold **300**. Air displaced by the sealant mixture **250** may vent from the die via leakage through and along the armor **138***i,o*. The sealant mixture **250** may flow around and along the annulus **312** until the sealant mixture **250** encounters the seals **320**. Pressure in the mold **300** may increase and the sealant mixture **250** may be forced into the armor **138***i,o*. Sealant penetration into the cable **130** may be stopped by the outer jacket **136**. Pumping of the sealant mixture **250** may continue until the mold **300** is filled.

FIG. **4**D illustrates a portion **150** of the cable **130** impregnated by the sealant **250**. Once the sealant **250** has cured and cooled to at least a point sufficient to maintain structural integrity, hydraulic pressure may be relieved from the ports **319**. The winch **124** may then be operated to pull the sealed portion **150** free from the mold **300** and may continue winding the cable **130** until an end of the cable is above the mold

300. The mix head may be disconnected from the mold **300**. The mold **300** may be disconnected from the BOP **110**. The service truck may stow the mold **300** and mix head and leave the wellsite.

FIG. **3**B illustrates the ESP **105** and the stuffing box **115** being lowered toward the tree **50**. The cable **130** may then be inserted through the stuffing box **115** and fastened to the cablehead **105**. The boom **125** may be used to hoist the ESP **105** and stuffing box **115** over the BOP **110**. The ESP **105** may be lowered through the tree **50** and into the wellbore **5** until the stuffing box **115** engages the BOP **110**. Lowering may be halted and the stuffing box **115** may be fastened to the BOP **110**. Lowering of the ESP **105** into the wellbore **5** may resume until the ESP is at the deployment depth.

FIG. **3**C illustrates the ESP **105** deployed and operating. As the ESP **105** is lowered to the deployment depth, the sealed portion **150** may be lowered into alignment with the stuffing box seal. The isolation device **106** may then be set to engage the production tubing **10***p* and the stuffing box **115** may be operated to engaged the sealed portion **150**. The ESP **105** may then be operated to pump production fluid **35** from the wellbore **5** to the tree **50** and through the tree to the surface separation, treatment, and storage equipment.

Advantageously, the sealed portion **150** obviates the need for grease injection while the ESP **105** is operating. Once the ESP **105** needs to be retrieved from the wellbore **5** for maintenance and/or replacement, the cable **130** may be inspected and reused to deploy the repaired/replaced ESP into the wellbore, the cable may be replaced and resealed, or the sealed portion may be cut and the remaining cable resealed to deploy the repaired/replaced ESP into the wellbore.

Alternatively, the cable **130** (with sealed portion **150**) may be used to deploy and operate other downhole tools besides an ESP, such as a compressor.

While the foregoing is directed to embodiments of the present invention, other and further embodiments of the invention may be devised without departing from the basic scope thereof, and the scope thereof is determined by the claims that follow.

The invention claimed is:

1. A method of deploying a downhole tool into a wellbore, comprising:

lowering a cable into the wellbore;

after lowering the cable, engaging a mold with an outer surface of the cable;

injecting sealant into the mold and into armor of the cable, allowing the sealant to cure, and disengaging the mold from the cable, thereby sealing a portion of the cable;

lowering the downhole tool to a deployment depth using the cable;

engaging a seal with the sealed portion of the cable; and

operating the downhole tool using the cable.

2. The method of claim **1**, wherein:

the downhole tool is an electric submersible pump, and

the electric submersible pump is operated to pump production fluid from the wellbore.

3. The method of claim **1**, further comprising connecting the downhole tool to the cable.

4. The method of claim **3**, wherein:

the downhole tool is connected before lowering the cable, and

the cable is used to lower the downhole tool into the wellbore.

5. The method of claim **3**, wherein:

the downhole tool is connected after injecting the sealant, and

the cable is used to lower the downhole tool into the wellbore.

6. The method of claim **1**, wherein:

the mold comprises a pair of semi-tubular housing segments and seals, and

the mold seals are engaged with the cable by assembling the segments around the cable.

7. The method of claim **1**, wherein:

the cable is inserted through the mold, and

seals of the mold are engaged with the cable by operating respective actuators of the mold.

8. The method of claim **1**, wherein the sealant is a polymer.

9. The method of claim **8**, wherein:

the sealant is a mixture of a resin and a hardener, and

the resin and hardener are mixed as the sealant is injected into the mold.

10. The method of claim **8**, wherein the sealant is molten when injected into the mold.

11. The method of claim **1**,

further comprising connecting a stuffing box to a wellhead, wherein the stuffing box comprises the seal.

12. The method of claim **1**, wherein:

a length of the cable is greater than or equal to five hundred feet, and

a length of the sealed portion is less than or equal to one-tenth of the cable length.

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